The Late Field Life of the East Midlands Petroleum Province – A New Geothermal Prospect?

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Abstract: Modification of existing oilfield infrastructure could deliver a cost effective way to extend the economic life of depleted onshore oilfields. Naturally warm connate and injection water contained within these fields could be initially co-produced with remaining oil reserves and used to deliver clean, cheap, non-intermittent heating. The East Midlands Petroleum Province contains over 30 fields with a production history spanning 95 years (Craig *et al.* 2013), and we have chosen to examine the Welton field in detail. Well data for the Welton field has been analysed to ascertain extractable heat within both oil and non-oil (water) bearing strata within the field. Production rates were calculated to be 728 m^3 d^{-1} oil and 854 m^3 d^{-1} water. These values also include productivity of intervening largely water bearing intervals. Target formation temperature at 1500 m was determined to be 52.5°C, allowing an extractable heat energy calculation to be undertaken for a range of temperature differentials. For a 30°C depletion in temperature, 1.6 MW_t extractable heat is available within the Welton Field alone. This equates to 14,040 MWh of heat energy available for consumption by the domestic market or within commercial greenhouses.

Deep geothermal energy extraction is a technology that is little developed within the UK, yet has scope to be a major component of the renewable energy industry. In the UK, this type of energy resource is currently only used on a small scale in Southampton, where one single well exploits water at 76°C from the Triassic Sherwood Sandstone aquifer (1729-1767 m TVD) within the Wessex basin. This particular sandstone unit displays both lateral and vertical permeability that has allowed water to be pumped at a rate of 864 – 1037 m^3 d^{-1} (Williams 2014, pers. comm.). The heat contained within this water is used to both heat and chill retrofitted public buildings within the centre of Southampton, and also provides heat for approximately 400 domestic flats (Southampton City Council, 2009). A total of 14,000 MWh of heat is produced per annum from this well, which equates to 18% of the total district heating mix (the remainder being provided by fuel oil and natural gas).

A recent Deep Geothermal Review Study of the UK (Atkins, 2013) focused on assessing geothermal power generation alone, with any excess heat considered as a potential usable by-product. However, low enthalpy geothermal resource exploitation (heat for heat) is seen by many as a more viable proposition. Geothermal systems extracting heat from deep onshore saline aquifers have already been proven to be a viable resource both in the UK (Gale & Rollin 1986) and across Europe. The Paris District Heating Scheme currently operates 34 well doublets, extracting warm water (54-80°C) from the Mid Jurassic Dogger Formation. This limestone aquifer has produced a yearly total of 1,240 GWh when producing from all 34 doublets (Lopez *et al.* 2010). Germany has also seen a geothermal renaissance having developed over 200 direct use deep geothermal systems. Operating geothermal systems have an installed geothermal capacity of 250 MW_t (Agemar *et al.* 2014) producing 925 GWh yr^{-1} consumable energy for district heating, space heating and thermal spa use. This does not include the additional contribution made by shallow / near surface geothermal systems. Geothermal power production has risen to an installed capacity of 27.1 MW_e, equating to 36 GWh yr^{-1} consumable energy.

The cost of geothermal energy

The primary cost driver in constructing a geothermal scheme is that associated with the drilling of a geothermal borehole. It is estimated that 60-70% of the total cost of a geothermal scheme is spent on the drilling phase (ARUP, 2011). The Science Central borehole, drilled in Newcastle-Upon-Tyne between 2011-12 to 1.8 km depth, cost approximately £1.2m to drill (Younger *et al.* 2012); logging, testing and completion of the borehole would more than double this cost. This exploration borehole was drilled to test the possibility of a geothermal resource being associated with a large fault zone located in the area of concern (the Stublick-90 Fathom Fault Zone). Should the resource be available, a combined heat and power generation scheme could be implemented (Younger *et al.* 2012).

Control over drilling costs substantially reduces the inherent risk associated with geothermal schemes. One way to control such costs is to use existing infrastructure (both surface and subsurface) to de-risk a potential geothermal exploration target. Such a scheme exists in Tøndor, Denmark (Sanchez & Ofori, 2013). Wells drilled by DONG Energy during the 1980's were sunk in order to explore the hydrocarbon potential of an anticlinal structure. Target strata were the Early Triassic Sherwood Sandstone Group (formerly Bunter Sandstone), present at 1786-1885 m below ground level. Five wells were drilled but only one indicated a reasonable gas show, and as such the area was abandoned as a hydrocarbon prospect. These wells and all associated well data were then utilised more recently in order to assess the geothermal prospect of the area. Temperatures of 75°C and flow rates of approximately 4804 m^3 d^{-1} are achievable, and may produce an equivalent electrical output of 16 MW (Sanchez & Ofori, 2013). This project is unique as it effectively "recycled" existing oil well infrastructure for use as a geothermal exploration target, saving both time and money.

Within the UK, in a manner similar to the Tøndor scheme, there is scope to utilise existing oil well infrastructure associated with onshore oilfields for geothermal purposes. One such onshore oilfield is the East Midlands Petroleum Province, which exploits from

Carboniferous strata that underlie the area. Whilst the flow rates from Carboniferous strata are not comparable with those quoted from Permo-Triassic sediments, the key point is the wells and infrastructure are already present. The risk and cost of drilling wells has already been taken on, with the by-product (warm water) now being a source of free heat energy that can be exploited by a geothermal scheme.

Previous Geothermal Exploration

An assessment of geothermal resource availability within the UK was undertaken between 1976 and 1986 in response to the oil crisis experienced during the 1970's. A major part of the assessment focused on quantifying the resource contained within Mesozoic Basins. A total of seven boreholes were drilled across the UK during this phase of geothermal exploration: four of these boreholes specifically targeted low enthalpy Mesozoic basins, whilst the remaining three investigated the high enthalpy resource associated with the Carnmenellis Granite, Rosemanowes, Cornwall. Carboniferous sediments were not fully quantified with regards their geothermal potential during the study due to lateral variability, post deposition cementation and complex structural features exhibited within these deposits (Holliday, 1986). These parameters affect aquifer properties and makes prediction of permeability, porosity and flow volume difficult to estimate for large areas. Sandstone units, particularly those of Westphalian (Early – Mid Pennsylvanian) age, can be difficult to trace laterally across large areas; units that do display large areal extent can display widespread heterogeneity in permeability and porosity. Namurian Millstone Grit (late Mississippian – early Pennsylvanian) sandstone units display variations in both porosity and permeability, with the former varying between 7% and 20%. Permeability can vary between 1 mD and 30 mD (Holliday, 1986; DECC, 2010). Recorded production rates from water bores abstracting directly from the Millstone Grit have been shown to vary between 43.2 $m^3\ d^{-1}$ (0.5 L s^{-1}) and 4320 $m^3\ d^{-1}$ (50 L s^{-1}) (Holliday, 1986).

Carboniferous sediments of the East Midlands were initially deposited in an equatorial marine environment, with an increasing shift towards a fluvio-deltaic environment forming throughout the Carboniferous (Holliday, 1986; Collinson, 2005; Glennie, 2005). Therefore, proximal and distal sediments produce large variations in grain size and sorting. This introduces the heterogeneity that is problematic when characterising Carboniferous geothermal systems, and has led to an incomplete quantification of the total geothermal resource available within these systems. However, with the aid of data from oil wells which exploit Carboniferous strata within the East Midlands Petroleum Province, such units can be much better characterised. This opens a new novel way of researching into resource quantification in this area.

STUDY AREA

The East Midlands Petroleum Province is an extension of the Southern North Sea Basin and comprises a series of NE-SW trending concealed Carboniferous basins (DECC, 2010). These basins have long been known to contain both oil and gas fields; oil was first extracted for commercial use at Hardstoft, Derbyshire in 1919 (Craig *et al.* 2013). Additionally, the UK's largest onshore gas field was discovered at Saltfleetby, East Midlands (Hodge, 2003). Over 30 oilfields have since been discovered in the East Midlands, all located west of the Derbyshire Dome (Figure 1). Peak oil production across the East Midlands occurred initially during the 1970's in response to increased oil prices imposed by O.P.E.C. The 1990's saw somewhat of a renewal in interest across the area, with peak oil figures occurring during this time. More recently, increasing water cut within all fields has seen many wells being shut in.

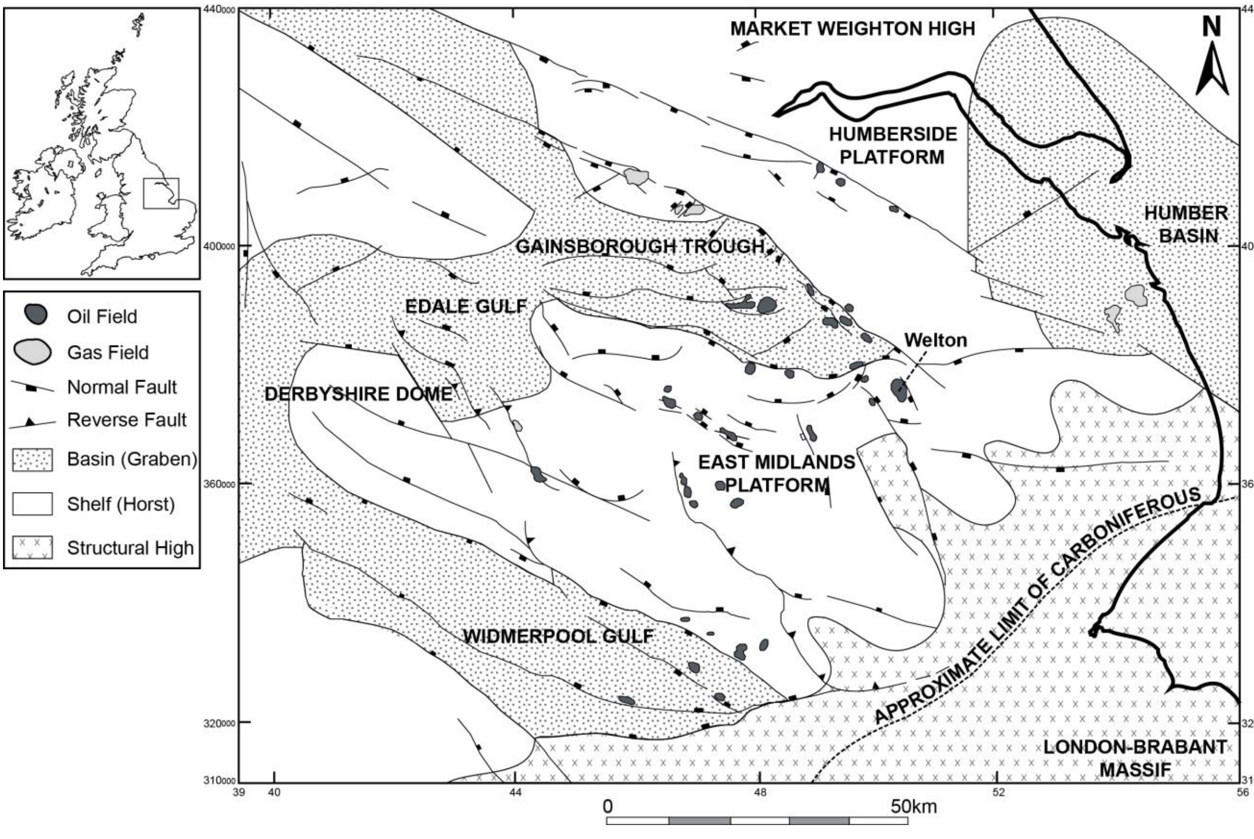

Figure 1: The East Midlands Petroleum Province. The Carboniferous block and basin structure across the East Midlands has been identified on the map, along with associated oil and gas fields (DECC, 2010).

The Welton Field: Location & Stratigraphy

The second largest onshore oil reserve in the UK (to Wytch Farm on England's south coast) was discovered at Welton in 1981 (DECC, 2010). Located 8 km northeast of Lincoln City, the Welton field has 45 penetrations associated with it (80 individually named wells in total), the base of which range between 1169 m (Welton B28) and 2536 m (Welton A1) true vertical depth (TVD). Of these individual wells, 45 have temperature data and 22 have porosity and permeability data. Between 1981 and 2008, 2,699,245 m^3 oil were produced from the field. The field has three sites where wells are clustered; the 'A' site, 'B' site and 'C' site, as detailed on Figure 2. Wells in the 'A' site primarily exploit strata in the northern half of the field, whilst wells in the 'B' and 'C' site target central and southern areas.

Figure 2 shows the general location of the Welton field, along with the distribution of wells across the area. The field is located on the East Midlands Platform; a fault bounded block south of the Gainsborough Trough (see Figure 1). This trough formed one of the main depocentres of sedimentation during the Carboniferous, and hosts several oilfields including Gainsborough, Beckingham and Glentworth.

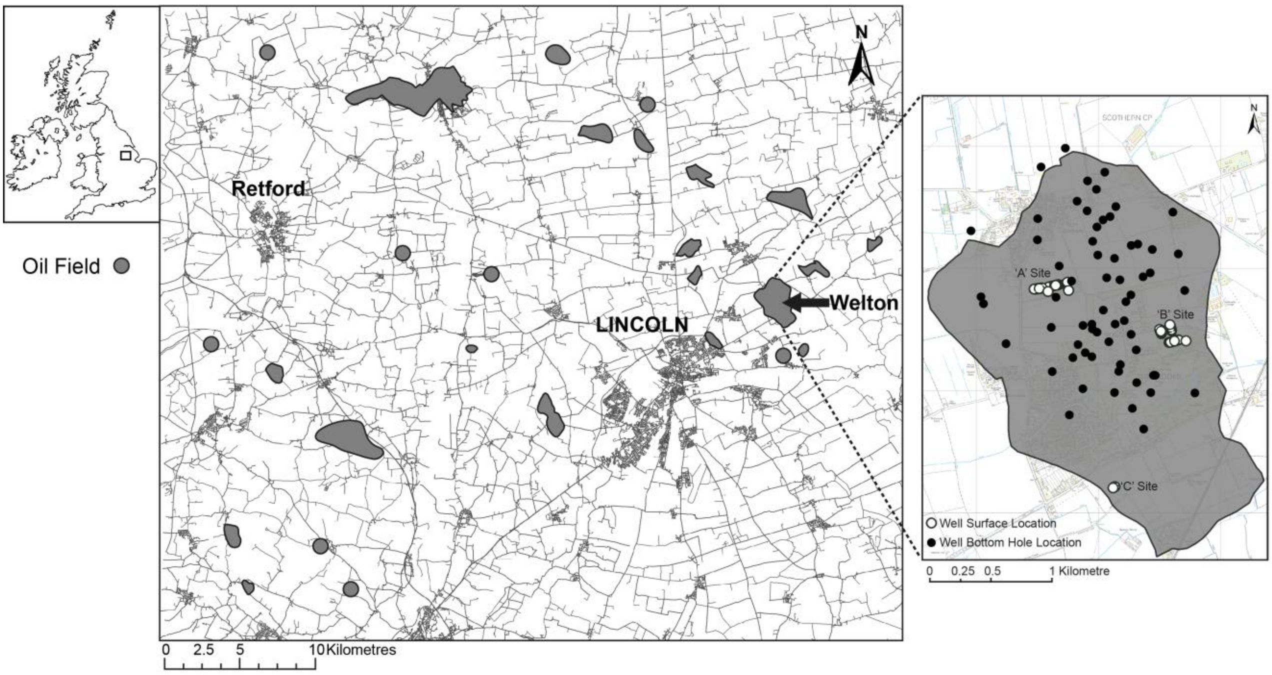

Figure 2: General location of the Welton field and associated oil wells.

Target Strata

Within the Welton field there are three major oil producing strata. These are the following:

(a) Pennine Middle Coal Measures - Westphalian 'B' : Brinsley-Abdy Rock;
(b) Pennine Lower Coal Measures - Westphalian 'A' : Upper Succession (Deep Soft Rock, Deep Hard Rock, Parkgate, Tupton);
(c) Pennine Lower Coal Measures - Westphalian 'A' : Basal Succession (Unit 1a, 1b, 1c, 2a, 2b, 2c, 3a, 3b).

These strata are generally comprised of fine to coarse sandstone interbedded with siltstone and mudstone intervals. In addition to these strata, one well (A4) has produced from the Dinantian Limestone (Craven Group). This is not considered as an important oil producer, but will be considered as a geothermal reservoir for reasons outlined further on within this section. The Brinsley-Abdy unit will not be considered as a geothermal reservoir due to its relatively shallow depth and thus correspondingly lower reservoir temperature. All horizons are marked on the stratigraphic column and generalized cross section in Figure 3. Approximately 67% of wells drilled in the Welton field target the Basal Succession, whilst 23% target the Upper Succession and 8.5% the Brinsley Abdy. Most wells are completed in only one of the oil bearing intervals as there is lateral variation in the structure and form of these units across the field. The lower successions are generally inter-bedded with siltstone, sandstone and lower porosity / permeable mudstone units, and in some cases there is variable cementation that reduces the net pay of the unit (DECC, 2010).

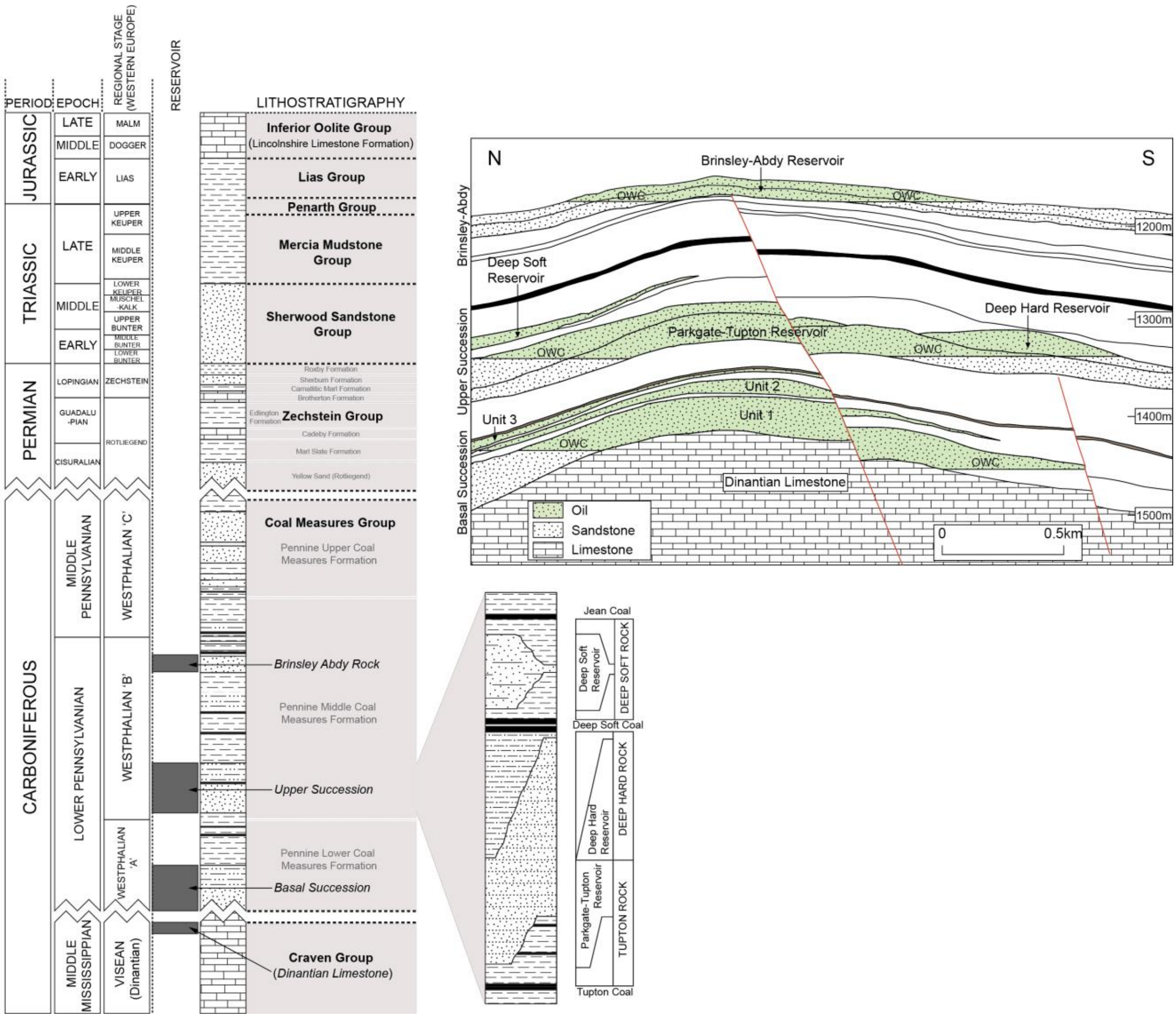

Figure 3: Summarised stratigraphy and structure across the Welton field (after Roc Oil, 1999).

Upper Succession

This producer is comprised of several sand bodies, namely the Deep Soft Rock, Deep Hard Rock and Parkgate/Tupton units. These are displayed on the expanded section within Figure 3. The Parkgate/Tupton unit and Deep Hard Rock are present across the entire Welton field, whilst the Deep Soft Rock is more difficult to trace and displays lateral heterogeneity.

Deep Soft Rock

Well records have described the Deep Soft Rock as fine grained quartzose sandstone, moderately to well sorted with varying degrees of siliceous or calcareous cementation. The unit has been interpreted as fluvio-deltaic facies sediments. Within the northwest of the Welton field (exploited by the 'A' site) a major NE-SW trending channel has been interpreted, identified by wells displaying successive fining up sequences. Non-productive wells in the area encountered interlaminated mudstones and sandstones, or mudstone only which have been interpreted as channel bank deposits. In the area surrounding the 'B' site, coarsening up sequences have been identified and interpreted as crevasse splay deposits that are related to another possible channel sequence to the east of Welton. The 'C' site has been interpreted as being more proximal to this channel, which explains the reduction in net pay of the Deep Soft Rock at the 'C' site.

Deep Hard Rock

The Deep Hard Rock is generally comprised of a fine grained sandstone with varying levels of sorting (from poor to moderate) and weak siliceous/kaolinitic cement. The unit is occasionally interbedded with mudstone and sandstone, and rarely contains poorly sorted, angular conglomeritic sections. The facies has been interpreted as multiple channel events containing basal conglomerates, erosive channels and pinch out sand bodies. The net reservoir is well developed within a belt across the northeast of the Welton field, and a belt across the southern part of the field.

Parkgate-Tupton Rock

The Parkgate-Tupton Rock was initially classed as one sand body. In some areas there is a clear distinction between the Parkgate unit and Tupton unit. The unit as a whole is similar to the Deep Hard Rock. The unit varies from fine to coarse quartzose sandstones, poorly to moderately well sorted containing an argillaceous and/or siliceous cement with frequent conglomeritic horizons and fining up sequences. Some wells encountered thick beds of argillaceous mudstone interpreted as channel bank collapse, causing the entrainment of large mudstone blocks.

Basal Succession

Basal succession sedimentation has been interpreted to be on a lower delta plain, analogous to the Mississippi lower delta plain. In the Welton field it has been broken down into three broad reservoir units; Unit 1, Unit 2 and Unit 3. As shown on Figure 1, Welton lies on the structural high known as the East Midlands Shelf. Prior to the deposition of the Basal Succession, sedimentation rates across the Welton field were relatively slow because of this structural relief. The sub-basins surrounding the Welton field were steadily being infilled by a major deltaic deposystem bringing clastic material into these areas. The onset of sedimentation that formed the Basal Succession occurred when these basins were full. This resulted in multi-storey multi-channel systems developing across what was previously dominated by a prograding deltaic deposystem. The deltaic system continued to prograde onto the East Midlands shelf bringing coarse sand onto the irregular Dinantian karst limestone surface.

The Basal Succession is made up of three separate channel systems, with Unit 1 (the lowermost unit) being the thickest and most extensive. Unit 1 is, on average, a 33 m thick sand that has been interpreted to be a high-energy distributary channel system sealed by an overlying mudstone. Laterally within this unit, smaller crevasse splay deposits and interdistributary bay systems can be identified within core. Unit 2 has been identified as another smaller channel event and averages 11 m thickness. This is split further into zones 2a, 2b and 2c; the 2b zone has been identified as the sand-prone reservoir zone. This sand thins and is entirely replaced by a mudstone/siltstone equivalent in the southern part of the field, interpreted as the distal equivalent. Averaging 9 m, Unit 3 is the thinnest of the Basal Succession units and is similarly split into 3a and 3b. Zone 3a is a thick mudstone unit, whilst 3b is a single channel sand deposit that thins to a silt towards the south of the field.

Dinantian Limestone

The full thickness of the Dinantian Limestone has been proven by only one well: Welton A1. This well encountered 993 m of limestone before entering Carboniferous volcanics at the base of the succession. Pre-Cambrian basement was then penetrated (noted to be chloritic phyllite). In general, however, wells penetrate anywhere between 23 m and 108 m into the limestone. The overlying Basal Succession sits unconformably on the Dinantian Limestone, the surface of which is irregular, undulating and generally weathered. Well records indicate in four wells there is a medium – coarse, moderately sorted, sub-angular sandstone interval (<40 m) of Dinantian age overlying the main carbonate sequence with a maximum recorded air permeability of 972 mD and porosities ranging between 12-17% (Well A2). This is called the ‘clastics’ sequence which does not appear to be laterally persistent.

Evidence of vertical homogeneity is not seen in any well record which reflects the weathering of the limestone surface prior to deposition of the Basal Succession. Where the ‘clastics’ succession is not seen, the limestone tends to grade from chalky amorphous limestone to micritic limestone through to crystalline limestone with abundant stylolites, many of which contain bituminous resin. Oil bleed has been noted to occur from fractures and stylolites in 11 wells. Argillaceous interbeds also occur in upper sections of the limestone which are laterally discontinuous. Visible porosity can be vuggy but is mostly poor. Flow of both oil and water is through fracture flow rather than intergranular flow. Stylolites appear not to form barriers to flow in this area.

Core Data

Horizontal permeability (KH) versus porosity crossplots for the Deep Soft, Deep Hard and Parkgate-Tupton Rock can be found in Figure 4. Additional data taken directly from oilfield core reports have been presented in Figures 5a and 5b.

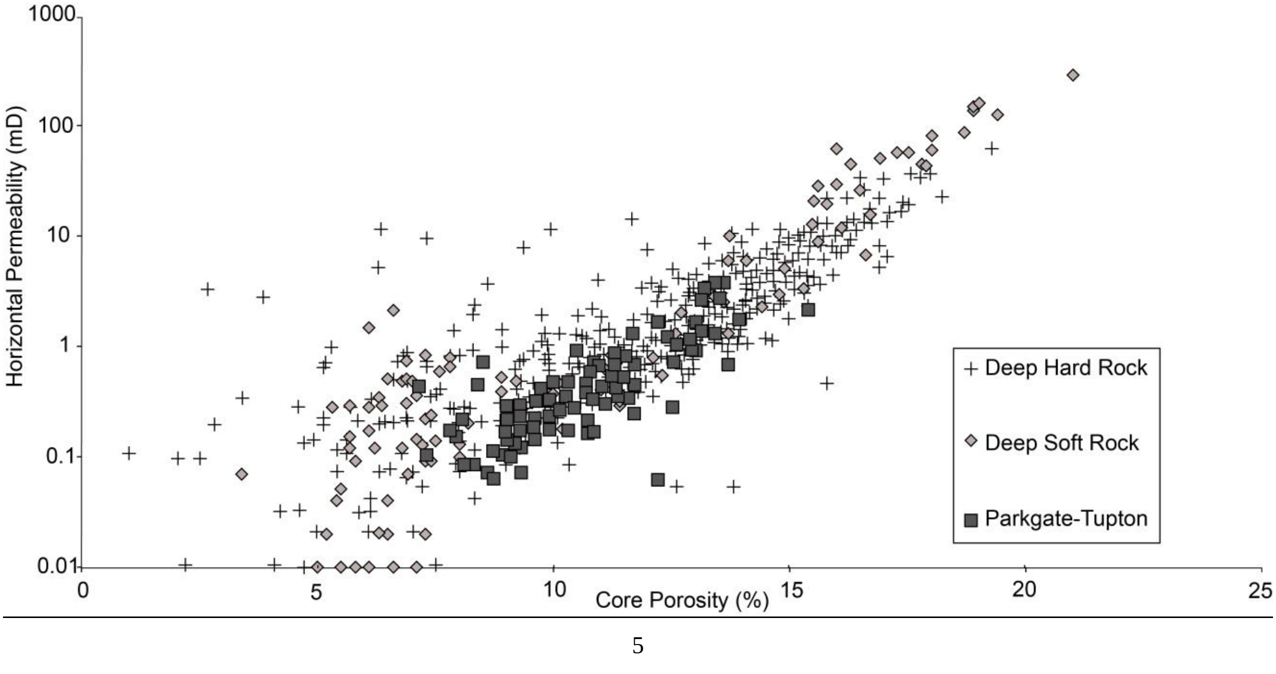

Figure 4: Summarised cross plot for data taken from the three main producing strata within the Upper Succession.

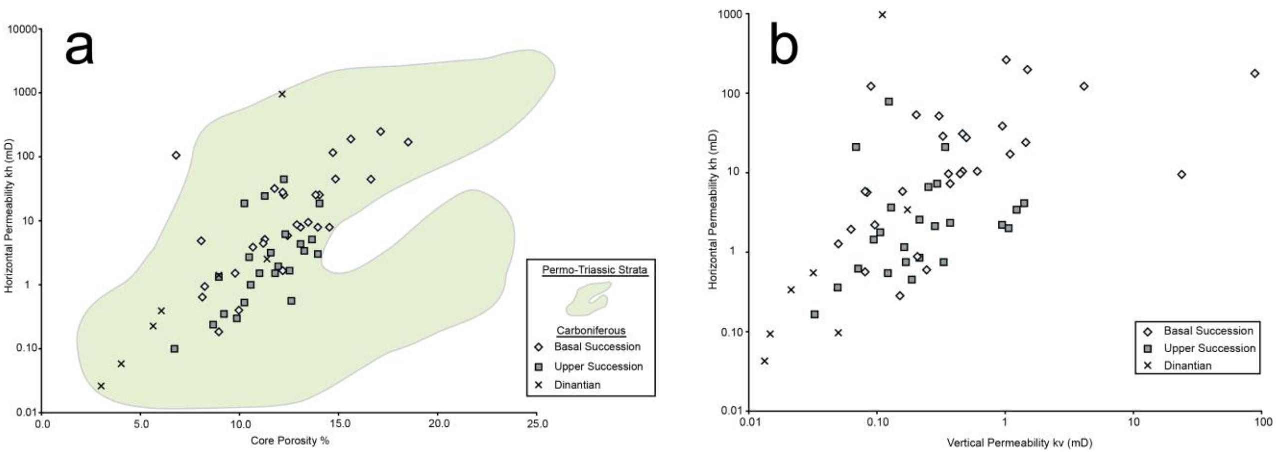

Figure 5a: Crossplot of data taken from oilfield core reports for the Welton field, with the shaded area indicating where Permo-Triassic sandstone and mudstone units plot for comparison (Permo-Triassic data from Colter & Ebbern, 1978). Figure 5b: KV/KH ratio for the three target successions within the Welton field. Data taken from oilfield core reports.

These plots have been interpreted within the discussion section of this paper.

METHODS

Temperature, pressure, density, specific heat capacity and flow rate data are available for the Welton field within well records held by IGas Energy PLC (IGas). These data were used to derive stabilised temperature, extractable heat value and well flow potential.

Horner Temperature Correction

Data accumulation from existing oil wells includes a measure of Bottom Hole Temperatures (BHT). In the majority of cases these values are not true representatives of the formation temperature; they represent the temperature of circulated drilling fluid which is at a lower temperature than the formation temperature (Deming, 1989; Förster, 2001). The recording of equilibration temperatures is uncommon due to the time required for the borehole to stand before equilibration is reached.

Deming (1989) provides a comprehensive comparison of the main methods of BHT correction. Many use an empirical approach to provide a temperature correction, whereas some use mathematical models in order to describe the temperature change within a borehole. The latter requires more information from the well records and as such can be harder to resolve. The most commonly used mathematical model utilised for temperature correction is the Horner plot. This takes the following form (Deming, 1989):

$$T\infty = BHT + A \log_e[(t + t_{circ}) / t]$$

Where $T\infty$ is equilibration temperature, A is an unknown constant, t is the shut in time (i.e. the time elapsed between cessation of mud circulation and BHT measurement) and t_{circ} is the drilling mud circulation duration. This method has its limitations as it requires at least two BHT measurements at the same depth but at differing values of t. Two values are also required in order to plot a time-temperature set. The gradient of this plot provides a value for the unknown constant A. Difficulty with this method arises as t_{circ} is not always noted on drilling logs thus making a requirement for a standard circulation time to be applied to the equation. In general, the amount of data required to calculate the temperature correction is rarely noted during drilling. In these instances a standard 4 hour circulation time can be applied where necessary (after Deming, 1989).

Temperature Gradient

The gradient has been calculated assuming a temperature of 10°C at ground level. This is to reflect the average ground temperature within the East Midlands when constructing geothermal gradients across the field.

Flow Prediction

Darcy's simple radial flow equation has been used to estimate the volume of fluid within strata that have not been used as an oil producer. It takes the following form (described in oilfield units after Economides *et al*. 2012):

$$q = \frac{k\ h\ (pe - pwf)}{141.2\ \mu\ B\ \ln(re/rw)}$$

Where pe represents external boundary pressure (psi), pwf represents internal bottom hole flowing pressure (psi), q represents flow rate (STB d^{-1}), B represents reservoir oil formation volume factor (res bbl/STB, where STB refers to Stock Tank Barrels), µ represents viscosity (cp), k represents permeability (mD), h represents aquifer thickness (ft), re represents the boundary radius (ft) and rw represents the wellbore radius (ft). Skin factor (a dimensional number used to describe any damage immediately surrounding the well bore that may impair permeability and subsequently pressure, caused as a result of invasion of drilling fluids into the formation) has been neglected from calculations. Oilfield units have been used in this instance as the data from well records is predominantly in this form. The resulting flow rate can be simply converted from STB d^{-1} to m^3 d^{-1} as 1 STB = 0.1589873 m^3. Rounding error in conversion of units for use in the standard radial flow equation can be avoided by using this method.

Extractable Heat Calculation

Extractable heat stored within water and oil has been calculated using the following equation:

$$Q = M_{dot} * C_p * \Delta T$$

Where Mdot represents mass flow rate (kg s^{-1}), Cp represents specific heat capacity (kJ kg^{-1} K) and ΔT represents the change in temperature (°C). In order to calculate mass flow rate the density of the fluid in question was taken from the well records, as were specific heat capacities for the oil and water present within the field.

ANALYSIS

Temperature

A total of 191 individual temperatures were recorded in well records. Of these temperatures, 26 wells had temperature data that satisfied the criteria required for the Horner temperature correction method to be applied. The corrected temperatures are displayed in Table 1.

Table 1: Horner-corrected temperatures

Well ID	T (°C)	T∞ (°C)	Average Depth mTVD	Temperature Increase (°C)	Epoch
A1	50.2	54.5	1599	4.3	Dinantian
A1	70.3	81.4	2536	11.1	Pre Cambrian
A2	48.9	52.3	1540	3.4	Dinantian
A3	49.1	49.2	1506	0.1	Dinantian
A4	49.2	49.8	1537	0.6	Dinantian
A5	44.4	44.4	1464	0	Dinantian
A7	49.2	53.4	1544	4.2	Dinantian
A9	51.4	52.4	1456	1	Dinantian
A10	54.7	55.7	1493	1	Dinantian
A10Z	60	60	1516	0	Dinantian
A11	51.5	57.6	1478.5	6.1	Dinantian
A18	53.5	54.1	1494	0.6	Dinantian
B1	45.5	47.2	1461	1.7	Dinantian
B2	46.9	50.1	1471	3.2	Dinantian
B2	49.3	50.3	1524	1	Dinantian
B3	46.1	50.3	1529	4.2	Dinantian
B4	49.4	52.8	1560	3.4	Dinantian
B7	50.5	54.2	1479	3.7	Dinantian
B8	50	50	1500	0	Westphalian
B8	54.6	58.8	1563	4.2	Dinantian
B9	52.4	57	1476	4.6	Dinantian
B10	45	45	1486	0	Dinantian
B15	52.2	52.2	1468	0	Dinantian
C1	49	54.6	1507	5.6	Dinantian
C2	48.4	51.2	1312	2.8	Westphalian
C3	50.7	53	1529	2.3	Dinantian

On average, the corrected temperatures are 2.7°C higher than those measured. This additional 2.7°C has been added onto the whole dataset, which has been plotted and displayed in Figure 6.

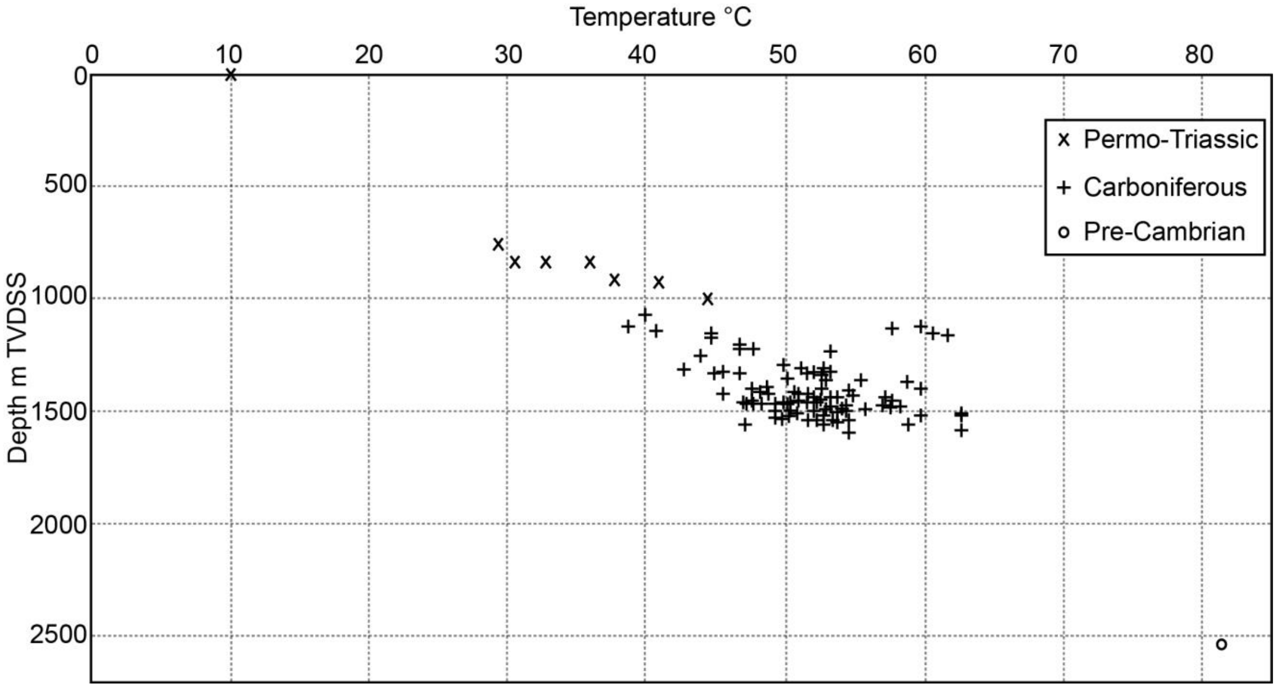

Figure 6: All corrected temperature data from the Welton field plotted vs. depth.

Temperature data have also been grouped by well in order to determine any spatial variation in gradient across the oil field. This required individual wells to have temperature measures in both Permo-Triassic and Carboniferous sediments. Five wells (A1, A4, B1, B8 and C2) satisfied these criteria, the results of which a displayed in Figure 7.

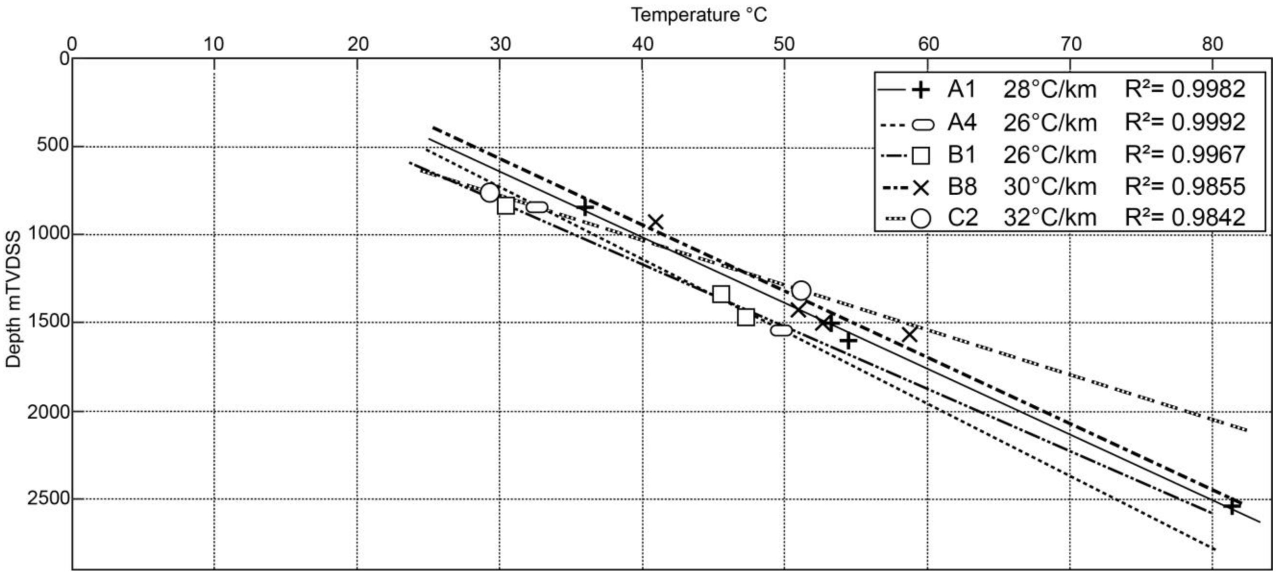

Figure 7: Temperature gradients for five individual wells.

Flow Rate

Production Rate

Oil and water flow rates from 45 wells recorded between November 1984 and September 2008 are displayed on Figure 8. Peak combined oil and water flow rates were recorded in 1997, totaling 343,584 m^3.

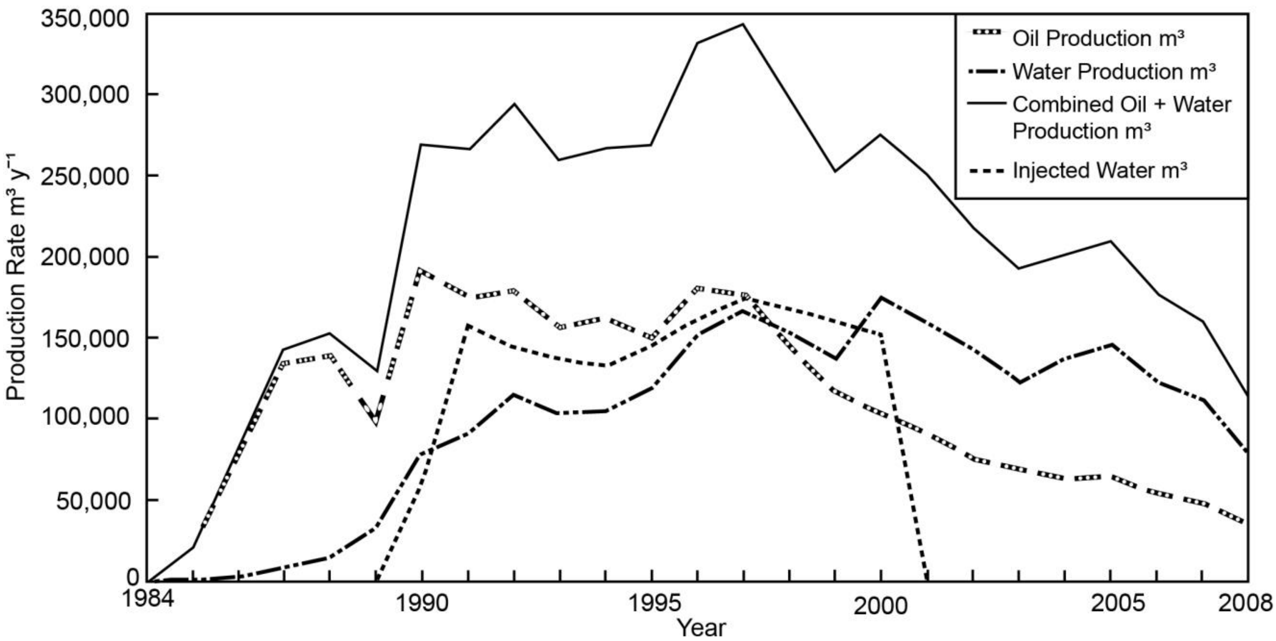

Figure 8: Combined oil and water production data summarized for 1984-2008. The data was recorded at well head on a monthly basis, which has been combined to produce yearly totals. Data taken from DECC (2013).

Drill Stem Test (DST) Data

Additional volumes of oil and water were calculated from Drill Stem Test (DST) data obtained for ten wells (A2, A4, A10, A11, B1, B2, B7, B8, B12, C4), with the remaining fluid volumes estimated using a simple radial flow calculation using the parameters based in Table 3. In the case of the above 10 wells, DST testing was undertaken on units that displayed potential to be an oil producer. In some cases the unit in question flowed water only, in which case it has not been taken into account in radial flow calculation. In other wells, oil was produced but it was not economic to complete within this strata, and in a similar manner has not been taken into account in production rate or radial flow calculations. Table 2 shows additional fluid from the wells described above.

Table 2: Drill Stem Test data from individual wells across the Welton field

Well	DST Target Unit	Volume $m^3\ d^{-1}$
A2	Upper Succession (Water)	2.9
A2	Upper Succession (Water + Oil Mix)	2.0
A4	Basal Succession (Water)	23.5
A4	Upper Succession (Oil)	8.6
A10	Upper Succession (Oil)	29.0
A10	Upper Succession (Oil)	7.0
A11	Dinantian (Oil)	3.8
B01	Upper Succession (Oil)	22.1
B01	Upper Succession (Water)	4.1
B02	Upper Succession (Water)	0.5
B02	Upper Succession (Oil)	3.6
B02	Dinantian (Oil)	4.6
B07	Namurian (Oil)	144.5
B07	Namurian (Oil)	20.9
B08	Dinantian (Water)	1.3
B12	Basal Succession (Water)	64.0
C4	Basal Succession (Water)	119.0

Additional Flow Estimation

Estimating additional flow rate using Darcy's simple radial flow required the definition of several fixed parameters. Formation temperature was taken as 52.5°C, Stock Tank Saline Water density was taken as 1.023 Mg m^{-3} (6.7°API) and average Stock Tank Oil density was taken as 0.848 Mg m^{-3} (35°API). Additional target reservoir parameters have been defined in Table 3.

Table 3: Radial flow parameters

<table>
<tr><th colspan="2">Target Unit</th><th>Thickness (mTVT)</th><th>Porosity (%)</th><th>Permeability (mD)</th><th>Formation Pressure MPa</th></tr>
<tr><td rowspan="3">Upper Succession</td><td>Deep Soft Rock</td><td>12</td><td>13</td><td>115</td><td rowspan="3">13.8</td></tr>
<tr><td>Deep Hard Rock</td><td>19</td><td>8.4</td><td>1.3</td></tr>
<tr><td>Parkgate-Tupton Rock</td><td>25</td><td>12</td><td>7</td></tr>
<tr><td>Basal Succession</td><td>Basal Succession</td><td>42</td><td>15</td><td>80</td><td>15</td></tr>
<tr><td rowspan="2">Dinantian</td><td>Dinantian</td><td>1000</td><td>8</td><td>0.22</td><td rowspan="2">15.2</td></tr>
<tr><td>Dinantian Clastics</td><td>31.6</td><td>16.2</td><td>-</td></tr>
</table>

Table 4 provides a summary of production rate data, DST data and radial flow data.

Table 4: Summarised flow rates for all productive strata

	Oil	Water
Production Rate $m^3 d^{-1}$	484	457
Drill Stem Test Data $m^3 d^{-1}$	244	217
Radial Flow $m^3 d^{-1}$	-	180

Revised flow volumes total 728 $m^3 d^{-1}$ oil and 854 $m^3 d^{-1}$ water. These values can now be used to calculate extractable heat from the Welton field.

Extractable Heat

The geothermal resource within Welton was calculated for a fixed ΔT value of 30°C. The results are summarised in Table 5.

Table 5: Extractable heat flow summary

	Oil	Water
Flow Volume $m^3 d^{-1}$	728	854
Flow Volume $m^3 s^{-1}$	8.43E-03	9.89E-03
Density Mg m^{-3}	0.848	1.045
Mass Flow Rate kg s^{-1}	7.12E+00	1.03E+01
Specific Heat Capacity kJ kg^{-1} K	1.8	3.93

Temperature Change (°C)	Heat MW_t	Energy MWh
30	1.6	14040

DISCUSSION

Reservoir Temperature & Geothermal Gradients

In the absence of heat flow values, the geothermal gradient has been calculated based on the temperature data obtained from well records. In order to calculate the thermal gradient at least two correct temperature data at different depths are required for each well. Considerations of glaciation and topography effects are also required prior to calculation of thermal gradient (Banks 2008). Glaciation and topography can perturb the geothermal gradient down to depths of 1.5 km (Westaway and Younger, 2013) before recovering to follow the regional thermal gradient. The majority of data presented is located within 1.5km from ground level. Whilst temperature data has been corrected for drilling-induced suppression, the topography and glaciation effect has not been corrected in this instance. The data can be considered a conservative estimate of temperature.

The line of best fit obtained for the whole dataset at Welton yields a temperature gradient of 29°C km^{-1}. Temperature data taken from Carboniferous strata alone does not correlate particularly well. The large spread and poor correlation of temperature data within the Carboniferous more likely reflects spatial variation in geothermal gradients across the Welton field. Given this data has been taken over a small depth interval (<500 m) as well as over a small surface area this is not unsurprising. Fitting a common gradient to the whole dataset, or to an individual geological time period, may not reflect the true gradient across the field. As such, further analysis of individual well gradients has also been used to corroborate this gradient. This spatial variation can be seen when individual well temperatures are plotted (Figure 7). An average of these temperature gradients has been calculated to be 29°C km^{-1}, which supports the initial gradient based on the total dataset.

Target Aquifer Properties and Variability

Within the UK, geothermal exploration has previously focused on deep sedimentary aquifers associated with Mesozoic-age basins. The aquifers contained within these basins are laterally continuous sand bodies which in some areas can produce between 864 – 1037 m^3 d^{-1} from a single well point (Smith, 1986; Williams 2014, pers. comm.). By comparison, the 45 penetrations located across the Welton field produce a similar total volume of fluid (728 m^3 d^{-1} oil and 854 m^3 d^{-1} water), but on average this equates to approximately 35 m^3 d^{-1} per individual well. Therefore, direct comparison between these two groups is not possible when assessing flow rate. Crossplots for target geothermal reservoirs within the Welton field are presented in Figure 4, 5a and 5b, which have also been compared with data taken from Permo-Triassic sandstone and mudstones from the Cheshire Basin. The two sets of data show some similarities in trend. However, the data for Carboniferous strata represents targeted core analysis on sections that were being proposed as producers for the oilfield, therefore, introducing a bias in the sampling. It does indicate there are comparable areas of porosity and permeability within the Carboniferous; however these are limited by their lateral extent.

KV/KH ratios were calculated based on core data. Again, this data is for target producing sands and as such introduces bias into the sampling. The data does indicate the sands have a stronger component of horizontal permeability than vertical permeability may be due to small scale features such as bedding.

The reduced transmissivity seen in Carboniferous target reservoir within the Welton field is problematic when determining the geothermal potential of a reservoir this age. However, in the case of the Welton field the impact of reduced transmissivity becomes negligible as the field is already operating. The risk of drilling and hitting unproductive strata will not occur as the risk has already been shouldered by the oilfield operator. The surface infrastructure is already in place to handle and separate fluid mixes before re-injecting waste water back into the field. The heat contained within produced water becomes a waste commodity, one which can be utilised in the vicinity of the field.

Extractable Heat & Heat Demand

The average cost of an ARUP defined median scenario (<10 MW) geothermal system has been estimated to be £5.6m (ARUP, 2011). Drilling costs typically account for 60-70% of the total expenditure for a geothermal project, with a further 24% spent on surface infrastructure. Reducing costs associated with drilling could, therefore, be the difference between the success and failure of a geothermal project. There are also significant gains to be made by reducing surface infrastructure costs.

Utilising a resource such as Welton benefits from having an existing oil well infrastructure. Wells penetrate transmissive oil and water bearing strata which have produced 2,699,245 m^3 of oil between 1981 and 2008. The Welton field is served by three drill sites: A site, B site and C site (shown on Figure 2). Oil and water that is removed from these areas is piped to the Welton Gathering Centre located at grid reference [TF045748] (Figure 9). Here oil, water and gas are separated from six individual fields, the largest of which is the Welton field. Separated oil is transported away by road tanker, gas is burnt onsite for power generation which then feeds onto the National Grid and water is re-injected (Guion *et al.* 2008). Given that mixed fluids are already being piped directly to the separating plant, additional costs associated with oil separation need not be considered in this instance as they are already being undertaken. The incorporation of heat pumps into the existing plant will be required and forms the initial expense (should heat be required for heating homes). The heat that is extracted from these fluids becomes an additional commodity, the use of which is limited by the location and type of heat demand.

The commercial value of the heat is currently un-quantified; the demand exists for such a commodity but there is currently no formal way to quantify its value. In this case study, the value of the resource has been put into context based on heat demand and usage within the area surrounding the gathering facility. Typically, low enthalpy geothermal resources are most effective when implemented as a District Heating Scheme, such as that seen in Southampton (Southampton City Council, 2009). A heat demand must be present in order for such a scheme to be effective due to excessive costs associated with transporting heat over large distances. Williams (pers.comm. 2014) estimates the price per kilometre of lagged pipework is approximately £1m, with an associated 0.5-1°C loss in temperature over the same distance (Cofely-GDF Suez 2012, Cofely-GDF Suez 2015). As such, heat demand surrounding the gathering centre at Welton has been assessed for potential heat users. Lincoln City (lying approximately 8 km southwest of the Welton field) has not been assessed within this study due to the associated temperature loss that will occur on transporting the fluid to Lincoln City Centre (up to 8°C).

Ofgem estimates per domestic household, the typical mid-range scenario gas consumption figure is 16,500 kWh per annum, whilst average electricity consumption totals 3,300 kWh (Ofgem, 2011). DECC (2013a) state that 66% of domestic energy consumption is used to provide space heating. Therefore, an average household can be assumed to consume 13,068 kWh of energy for space heating per annum. This figure can be used in order to determine the amount of domestic heat that could be offset by the Welton field using two scenarios.

- <u>Local Demand (<3km distance from Welton Gathering Centre)</u>

Approximately 2000 homes are located within a 3 km radius of the Welton Gathering Centre which will on average consume 26,136 MWh heat per annum. Assuming a ΔT of 30°C, the Welton field can produce up to 14,040 MWh. Therefore, 53% of homes within a 3 km radius could have their heat consumption cut to zero by the Welton field. If each household had 50% of their heat provided by the Welton field, approximately 2100 homes could benefit.

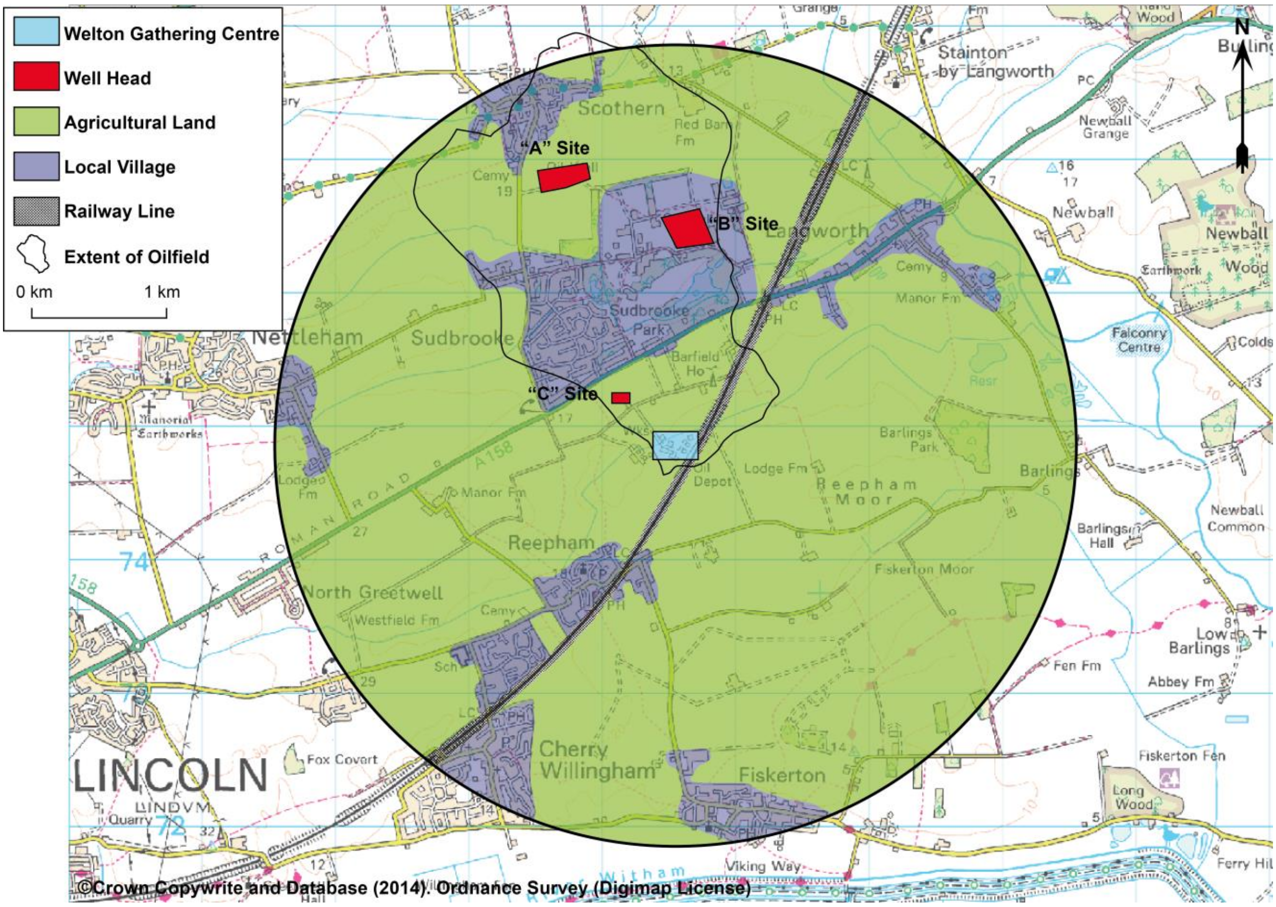

Figure 9: Land use within 3 km radius of Welton Gathering Centre.

To implement such a system would involve constructing a district heat network centered on the Welton Gathering Cente. When constructing such a scheme in an urban area, the costs can be very high. Since the area surrounding the gathering centre is primarily agricultural land, the costs are significantly reduced and could make this style of resource use viable.

- Agricultural Use: Commercial Greenhouses

Food production within the UK has seen a growing reliance on imported foodstuffs in order to meet consumer demand. Commercial greenhouses provide a means to produce seasonal crops year round whilst also guaranteeing a high yielding crop. Variables such as adverse weather do not impact as heavily on the crop, helping to smooth out peaks and troughs in food production.

The East Midlands forms a large swathe of land that is primarily arable farmland. Within a 1 km radius of the Welton Gathering Centre, 73% of the land is arable farmland, with 19% covered by local villages, 6% occupied by a railway line and the remaining 2% occupied by the Welton Gathering Centre and "C" Site as represented in Figure 10.

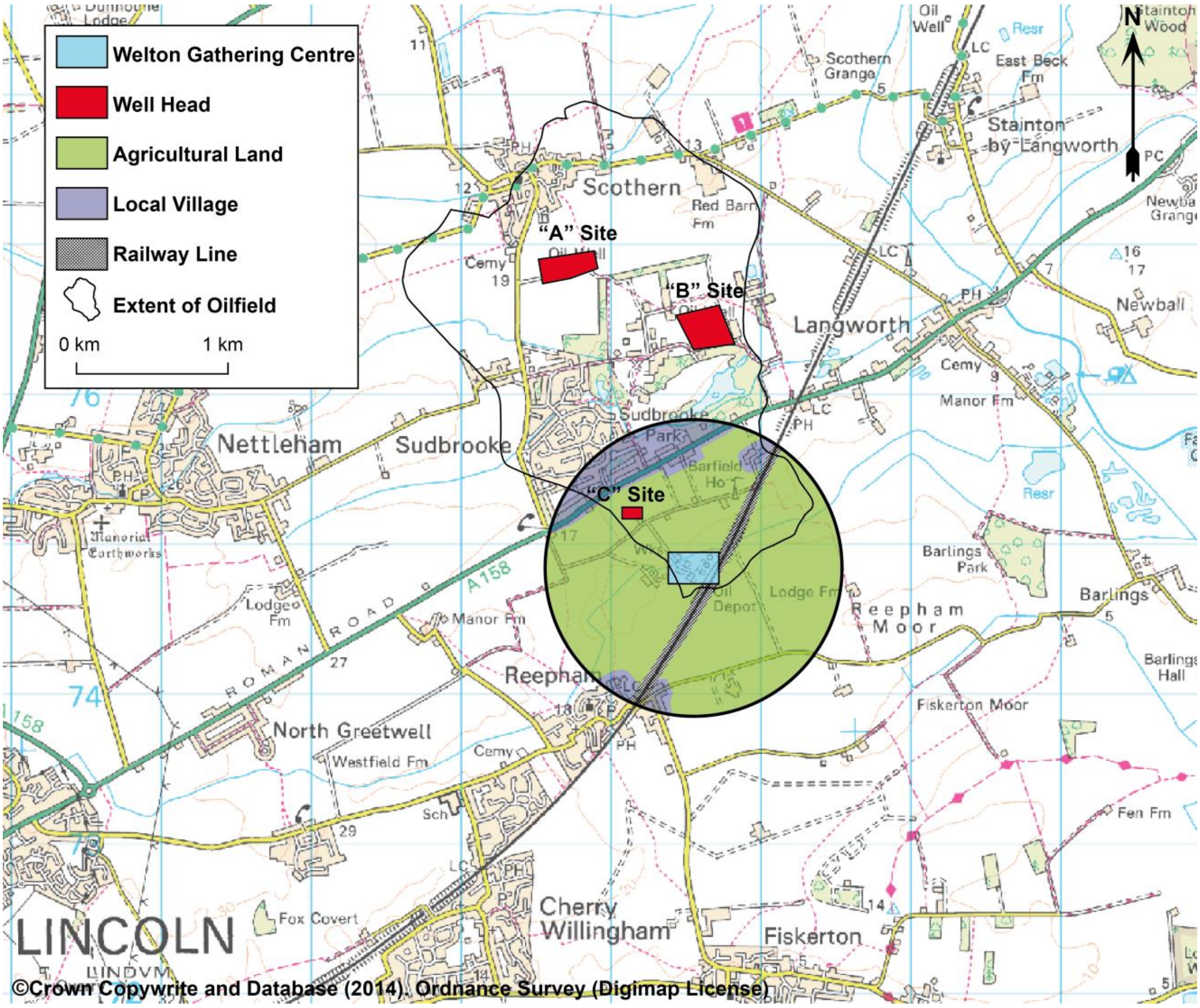

Figure 10: Land use within 1 km radius of Welton Gathering Centre.

The extensive agricultural land around gathering centre forms an opportunity for commercial scale greenhouses to be constructed. Temperatures within commercial greenhouses vary depending on the crop type being grown. The Carbon Trust (2004) indicate that energy intensive crops such as tomatoes, cucumbers and peppers require constant temperatures in excess of 18°C. Maintaining this temperature on a large scale is energy intensive and accounts for 90% of the energy used in commercial greenhouses (Sturm *et al.* 2012). Research undertaken by The Geological Survey of the Netherlands (Kramers *et al.* 2012) has suggested a minimum resource temperature of 45°C is required for commercial scale greenhouses to work, re-injecting at 25°C. This makes the area surrounding the Welton field a feasible site for a commercial greenhouse.

Typical heat demand for a commercial greenhouse varies due to crop type and whether the crop requires intensive or extensive management. Sturm *et al.* (2012) indicate extensive crops require a minimum 155 kWh m^{-2}, whereas intensive crops require up to 450 kWh m^{-2}. Based on 14,040 MWh of extractable heat being available, this equates to between 31,200 m^2 and 90,580 m^2 of land that commercial greenhouses could occupy which would benefit from 100% heat demand being provided by the Welton field.

CONCLUSION

Producing oil fields become less economically viable as oil rate declines and water rate increases. The produced water currently has no value, yet in many fields this water is at a temperature that could be used within a low enthalpy geothermal scheme. Within the UK, geothermal resources have been quantified with regards the low enthalpy geothermal resource held within Mesozoic Basins. Carboniferous strata have not been fully quantified due to their post deposition cementation and complex structural features (Holliday, 1986). Yet despite this one of the UK's largest onshore oil resources lies within Carboniferous strata within the East Midands. This proves there is enough transmissivity to permit water abstraction from these units.

The Welton field is part of the East Midlands Petroleum Province, and has produced 2,699,245 m^3 of oil between 1981 and 2008. An assessment of water temperature, flow volume, permeability and porosity has indicated that for a mid-range scenario (ΔT = 30°C), extractable heat totalling 1.6 MW_t is present. This equates to 14,040 MWh of heat energy available for consumption. This heat could be used very effectively to offset the heat demand of domestic dwellings located within 3 km of the Welton Gathering Centre. It could also be used to provide heat for commercial greenhouses covering between 31,200 m^2 and 90,580 m^2 of agricultural land. It is unlikely the heat can be transported to Lincoln City for use in a district heat network due to the large distances (8 km+) and associated temperature loss involved.

The Welton field is only one of over 30 fields within the East Midlands. Within a 10 km radius of the Welton wellhead, a total of nine other fields are present, five of which feed into the Welton Gathering Centre directly. In addition, the area of land between these fields is currently un-quantified with regards its hydrogeology and geothermal potential. This presents additional resources that are currently un-quantified, and provides an important insight into the geothermal resource held within Carboniferous strata.

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